Evaluation of Liquid-Phase Methanol (LPMEOH™) in a Low- NO_x Stationary Gas Turbine Combustor

Test Report

Report to
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1. Introduction

Today's model for the generation, transmission, and distribution of electricity relies on power generation at large, central power plants, and transmission, often over large distances, over an extensive high voltage grid to distribution centers. This model will see some amount of change in the future as distributed generation becomes a much more significant contributor. The impetus for distributed generation lies in:

- The relative inefficiency of the generation/distribution system due to transmission losses

- The constrained capacity of the transmission grid in certain areas of the country combined with the high capital cost of installing additional transmission capacity

- Environmental constraints that make it difficult to site and permit additional central power generating facilities

In addition, the recent deregulation of the electric utility marketplace, begun in California and completed in several other states, has stimulated additional economic incentives for small-scale distribution generation.

Gas turbine driven generator sets are currently the primary technology for providing distributed power. These have traditionally been installed in the 5 MW and higher capacity range. However, recent efforts by a number of turbine manufacturers, including Capstone, have led to the development and commercialization of small, low-cost turbines, termed microturbines, in sizes down to 25 kW. Moreover, these turbines are low emissions, high efficiency units owing the incorporation of a recuperator in their design.

When this project was first initiated in late 1997, an additional economic incentive for installing distributed generation capability at select industrial sites was envisioned, a pollution control incentive. In continuing attempts to bring ozone nonattainment regions into compliance with the National Ambient Air Quality Standard (NAAQS) for ozone, California and other states have been extending volatile organic compound (VOC) emission reduction mandates to smaller and smaller sources. As small industrial sources with gaseous emissions having very low VOC concentrations have very few cost-effective VOC control solutions, the concept of using the VOC-contaminated emission steam as combustion air in a small gas turbine in a distributed generation application seemed appealing.

Accordingly, the initial objective of this liquid-phase methanol (LPMEOH™) demonstration project was to demonstrate cost-effective VOC destruction from a small industrial stationary source by thermal destruction, with low oxides of nitrogen (NO_x) emissions, using a 25-kW stationary microturbine distributed power generator fueled with LPMEOH™. In Phase 1 of the project planned, a microturbine was to have been placed at a host site VOC emitter, operated for a two-week period, and tested for emissions and VOC reduction performance. In Phase 2, the turbine/generator was to have been operated for an extended period of time during which its power generation, fuel use, and emissions were to be evaluated. However, after an exhaustive search, no host site willing to participate in the project was forthcoming. In addition, the original project foresaw substantial interest and support from the California Energy Commission (CEC), through the Public Interest Energy Research (PIER) program mandated by the California legislation to deregulate the electric utility industry in the State. However, with no host site identified for the VOC destruction demonstration, it became clear that near-term CEC support for the project was not likely.

At this point it was decided to shift the environmental focus of the project. California, as well as the Federal Environmental Protection Agency (EPA), regulate NO_x as an ozone precursor. As a consequence, California continues to pursue very aggressive NO_x control strategies to facilitate bringing California ozone nonattainment regions into attainment. Moreover, such strategies will become more commonplace in the Midwestern and Northeastern states in response to EPA's decision to implement a NO_x cap and trade program in both the Northeastern states as well as the Midwestern states that contribute to the ozone nonattainment status of regions of the Northeast via transported ozone. EPA negotiated a memorandum of understanding (MOU) with the northeastern states to implement a cap and trade program that calls for substantial regional NO_x reduction. More recently, EPA issued a State Implementation Plan (SIP) call for the upwind Midwestern states to require similar substantial NO_x emissions reductions.

Given these mandates, it is clear that any new distributed generation capacity installed in California or these MOU and SIP call states will need to be low NO_x emitting units. In response to this need, Alzeta Corporation, with support from CEC, the National Energy Technology Laboratory (NETL) (formerly the Federal Energy Technology Center – FETC), and a number of gas turbine manufacturers, has been developing an advanced low NO_x surface stabilized combustor technology for stationary microturbines in distributed generation applications. The opportunity arose to participate in this program and extend demonstration testing to LPMEOH™. Accordingly, it was decided to redirect the LPMEOH™ demonstration project to focus on completing a series of tests using LPMEOH™ as a fuel for a low NO_x microturbine combustor targeted for use in a distributed generation application. This report summarizes the results of these tests. Section 2 of the report describes the Alzeta surface stabilized combustor technology, Section 3 outlines the test program performed, and Section 4 discusses test program results. Section 5 summarizes project conclusions.

2. The Alzeta Low NO_x Gas Turbine Combustor Technology

Alzeta has been developing the gas turbine semiradiant burner (GTSB) combustor for use in gas turbines since 1992. The key to the technology is stable operation at low adiabatic flame temperature. As shown in Figure 2-1, which is a plot of the rate of NO_x production (ppm/s) via the extended Zeldovich model of NO_x formation versus adiabatic flame temperature. As indicated in the figure, the rate of NO_x production at an adiabatic flame temperature of 2,800°F is 110 ppm/s. Thus, NO_x emissions would be about 1 ppm at combustor residence ties of 0.01 s, much lower than typical gas turbine combustor residence times. However, reducing the flame temperature to 2,700°F reduces the NO_x production rate by a factor of 3, allowing nominally 1-ppm emissions at proportionately longer combustor residence times.

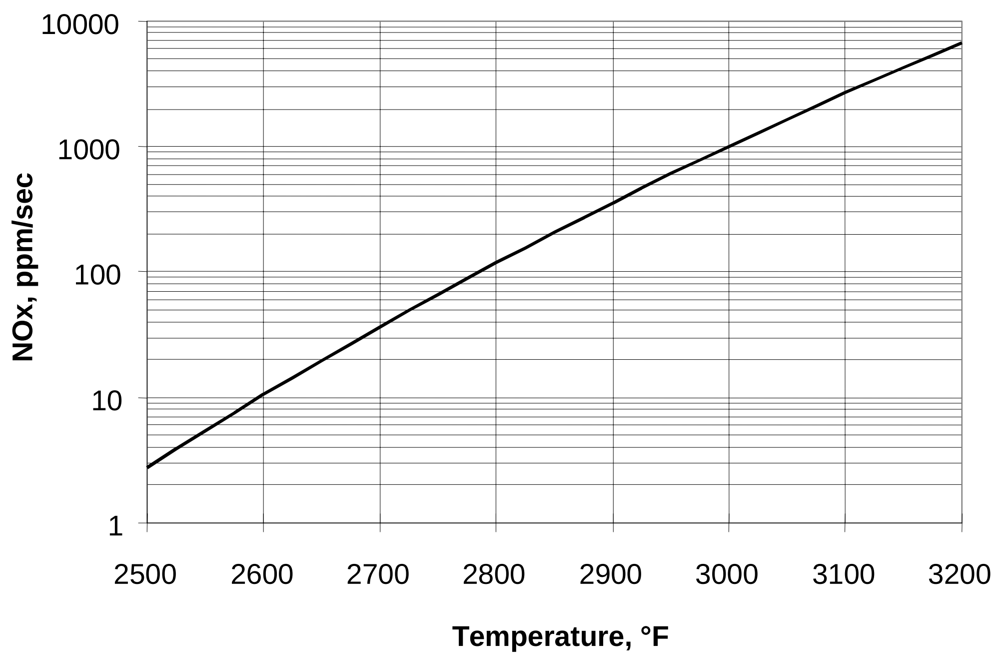

Figure 2-1. Predicted NO_x Production Rates

Since flame speed is also reduced rapidly with decreasing temperature, it is critical to develop methods to stabilize the flame front. In the GTSB combustor, this is done by first establishing a radiant flame zone over a porous metal surface. Premixed fuel comes through this low conductivity surface and burns in narrow zones, shown in the area denoted as A in Figure 2-2, as it leaves the surface. Secondly, adjacent to these radiant zones, the porous plate is perforated to allow a high flow of the premixed fuel and air. This flow forms a high intensity flame, area B in Figure 2-2, stabilized by the radiant zones. It is possible to achieve very high fluxes of energy, up to 2 MMBtu/hr/ft^2, while keeping adiabatic flame temperatures and NO_x emissions low.

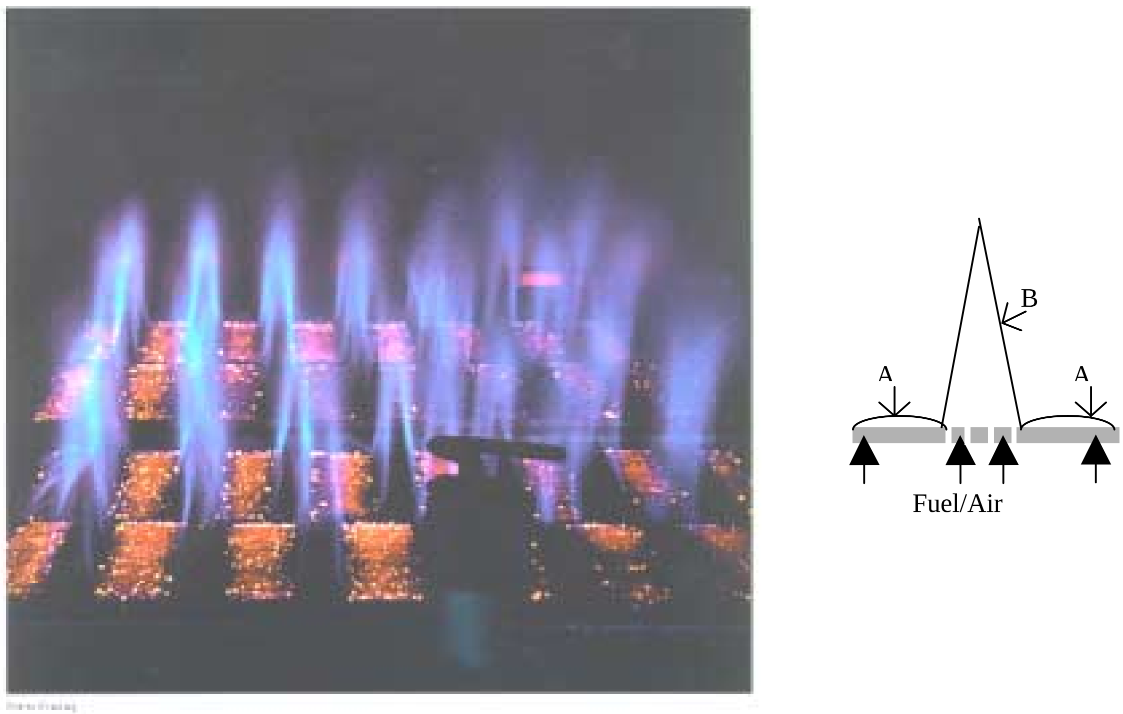

Figure 2-2. The Semiradiant Burner

The application of this technology to the high pressure, high preheat, and compact environment of microturbine combustor was the focus of the CEC PIER/NETL project. Typical microturbine combustors require volumetric heat release rates greater than 2 MMBtu/hr/ft^3. Testing of a combustor geometry under the CEC PIER/NETL project showed that these heat release rates could be achieved with emissions of NO_x and CO consistently below 2 ppm and 5 ppm, respectively, with natural gas fuel. The objective of the tests in this project were to evaluate whether similar performance could be achieved with LPMEOH™ fuel.

3. Test Program

The test program was carried out in the Alzeta test facility in Santa Clara, California. In testing performed in early 1999 with natural gas fuel, it was possible to achieve combustor NO_x, CO, and unburned hydrocarbon (UHC) emissions approaching 2 ppm at 15 percent O_2. Parallel testing with LPMEOH™ fuel was performed in these tests to evaluate whether comparable performance could be achieved.

Details of the test facility and the test program completed are discussed in the subsections that follow.

3.1 Test Facility

The tests were performed in the 10 kW prototype advanced low- NO_x turbine combustor at Alzeta. This test facility is a pressurized combustor capable of firing surface stabilized combustion burners comprised of a variety of surface materials at combustion pressures of up to 4 atm. The facility is equipped with a liquid spray vaporizer and enough residence time to completely vaporize methanol prior to entering the combustor itself.

A schematic of the facility as it was configured for these tests is shown in Figure 3-1. A house compressor serves to provide the combustion air as well as the LPMEOH™ tank pressure for LPMEOH™ fuel release. The burner chamber can be either air-cooled or water-cooled depending on the wall temperature desired. LPMEOH™ fuel is metered into a steam-heated heat exchanger where it is vaporized into the combustion air prior to introduction of the premixed fuel-air mixture into the combustor. Pressure control is achieved using an exhaust valve. Hot exhaust gases are cooled prior to entering this control valve in the water bath shown in the figure.

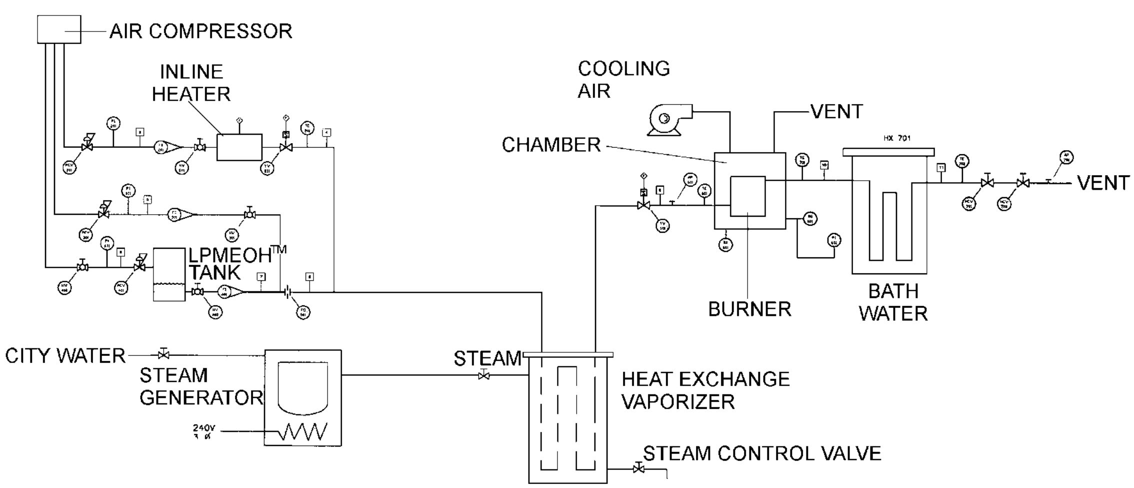

Figure 3-1. 10 kW Gas Turbine Combustion Test Facility Schematic

Photos of the facility are shown in Figure 3-2. The upper image shows the outside of the combustor and the bottom image shows the combustor with the primary combustion chamber unbolted. The 4” diameter metal-fiber pad can be seen in the center of the removed section. It is through this pad that the premixed gases pass shortly before they enter the stabilized combustion reaction. The flame shape formed with methanol is the same as shown in Figure 2-2. The size and shape of this chamber is representative of the combustors in a typical small microturbine. The flat-plate combustor is the simplest possible burner shape and is ideal if the total system-firing rate can meet the surface-firing rate required by the burner pad. In systems under 30 kW, typically this is the case. For turbines greater than 30 kW, a cylindrical combustor is used.

3.2 Test Plan

In gas turbine combustion, five operating parameters are important

- Combustor pressure
- Combustion air preheat temperature
- Fuel flow, or firing rate
- Total system air flow
- Air flow through the combustor (or percent air split between the combustor and the combustion gas dilution air)

In these tests, no additional dilution air was introduced downstream of the combustor, as Alzeta has shown in the past that this additional dilution air does not effect emissions. Its primary purpose is to lower the gas temperature to an acceptable level for the turbine blades, approximately 1,700°F for a microturbine. By removing the dilution air, the number of system variables was reduced from five to four for the tests. These were varied as follows:

- System pressure — this was varied from 1.5 to 3.4 atm, representing 0 to 100 percent load, respectively
- Combustion air preheat — preheat was held constant at 200°F. In an actual turbine, this value will change based on the polytropic compression of the turbine. In these tests, 200°F was the measured temperature after the LPMEOH™ was vaporized inside steam-heated tubes.
- Fuel flow, or firing rate — The combustor firing rate is directly proportional to the fuel flow, and was varied from 0.091 to 0.317 MMBtu/hr
- Total system air flow — this was varied from 17 to 75 scfm over the course of the test program

The target efficiency for a combustor with the properties listed above would be 30 percent, with current state-of-the-art technology delivering closer to 28 percent in reasonable air temperatures.

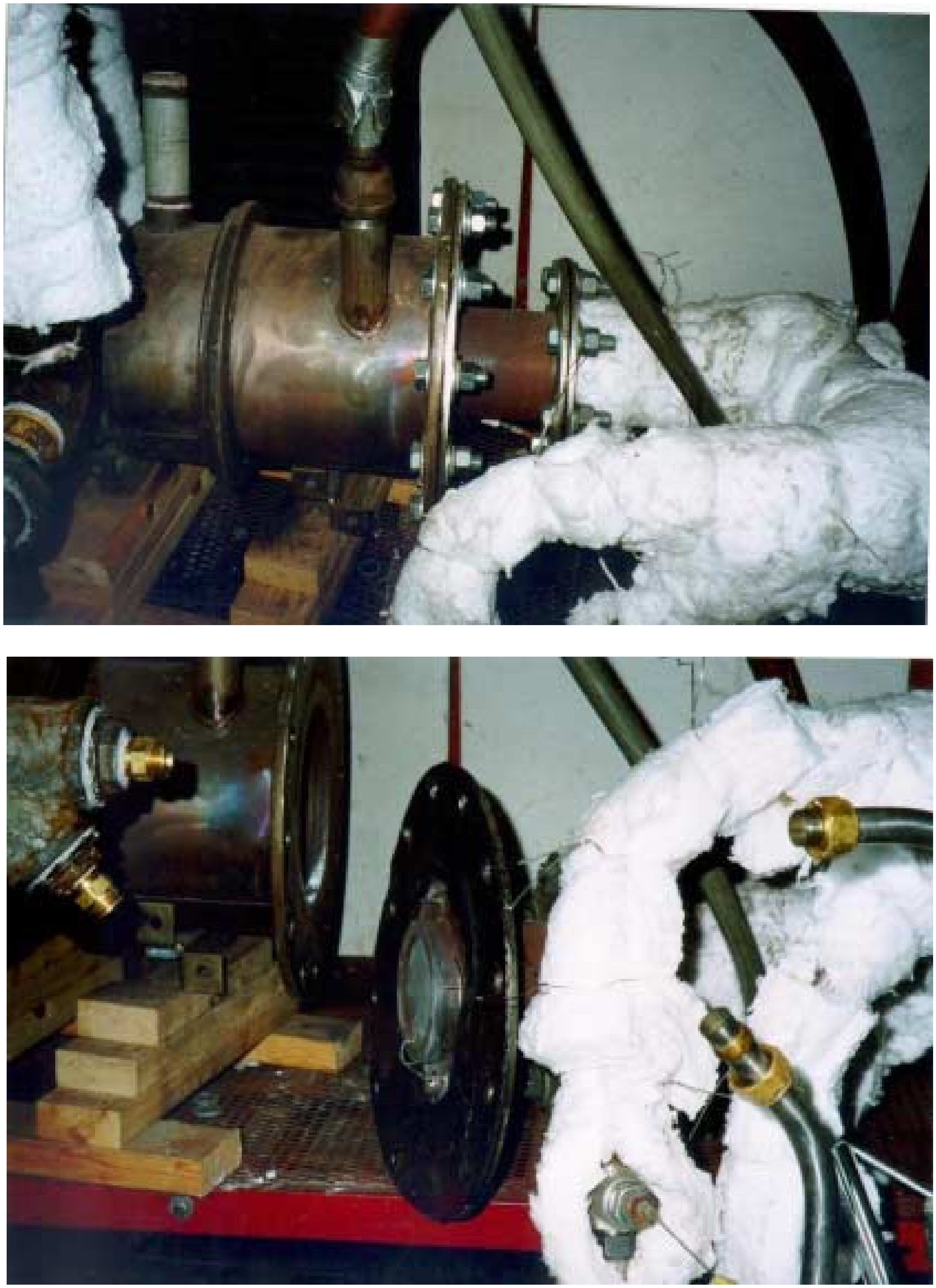

Figure 3-2. 10 kW Gas Turbine Combustion Test Facility: Photos

A matrix of test conditions varying the above parameters was tested and steady state emissions were measured. In addition, for one set of test conditions the combustor fuel flowrate was gradually increased at constant air flowrate and pressure while emissions were continuously monitored. This has the effect of gradually increasing the adiabatic flame temperature. These time-resolved measurements give a detailed picture of the broad range of adiabatic flame temperatures across which the combustor operates at low emissions with all other key turbine operating parameters held constant.

For all tests, the combustor exit gas concentrations of O_2, CO_2, CO, and NO_x were continuously monitored, as were fuel flowrate, air flowrate, combustor pressure, and system temperatures.

4. Test Results

Table 4-1 summarizes the results of a series of tests performed in the test facility under the CEC PIER/NETL program firing natural gas fuel in the combustor. Table 4-2 summarizes the results of the steady state tests performed in this project firing LPMEOH™ fuel. Comparing the data in the tables shows that the two test series were performed under comparable conditions, with the range of firing rates (MMBtu/hr) and combustor pressure tested being similar, although the natural gas fuel tests were performed at generally higher excess air levels with corresponding higher combustor exit O_2 levels than the LPMEOH™ tests.

The NO_x emission data from the tables are plotted versus combustor firing rate in Figure 4-1. Figure 4-2 is a corresponding plot of the NO_x emission data versus adiabatic flame temperature (AFT). The data in both figures show that NO_x emissions with natural gas fuel ranged from 2 to 7 ppm at 15 percent O_2 over the range of conditions tested. Corresponding emissions with LPMEOH™ fuel ranged from 1 to 6 ppm at 15 percent O_2. Emissions as low as 1 ppm at 15 percent O_2 were achieved at a number of test conditions, and 3 ppm at 15 percent O_2 or lower for all but the highest load tested. Figure 4-1 shows that the natural gas fuel tests extended to higher firing rates than the LPMEOH™ tests which, in turn, extended to slightly lower firing rates than the natural gas tests. In the range of overlap, NO_x emissions with the LPMEOH™ were comparable to lower than those with natural gas.

Figure 4-2 shows that the LPMEOH™ test conditions resulted in a greater range of calculated AFTs than the natural gas test conditions, with the LPMEOH™ tests extending to lower AFTs. NO_x emissions at the lower AFTs were comparable for the two fuels. At AFTs greater than 2,950°F, NO_x emissions with the LPMEOH™ fuel were consistently lower than with natural gas.

The CO emission data from Tables 4-1 and 4-2 are plotted versus combustor firing rate in Figure 4-3. Figure 4-4 is the corresponding plot of the CO emissions data versus AFT. The data in Figure 4-3 show that CO emissions with natural gas fuel were generally below 10 ppm at 15 percent O_2 over the firing rate range tested, with a general trend of slightly increasing CO emissions as firing rate was increased. However, for two tests, combustor emissions with natural gas fuel were in the 30 to 40 ppm at 15 percent O_2; one test had relatively high CO emissions at 75 ppm at 15 percent O_2.

CO emissions with the LPMEOH™ fuel were comparably low, at 4 ppm at 15 percent O_2 or less, in the 0.2 to 0.3 MMBtu/hr firing rate range. Emissions were increased at lower and higher firing rates than this range, but never greater than 27 ppm at 15 percent O_2.

The data in Figure 4-4 show that, with the LPMEOH™ fuel, CO emissions generally decreased with increasing AFT. This would be expected as higher flame temperatures would foster more rapid CO burnout. In contrast, with natural gas fuel, CO emissions appeared to increase with increasing AFT. Evidently, at the higher combustor excess air levels in the natural gas fuel tests, the decreased combustor residence times at increased AFT were insufficient for complete CO burnout even at the higher temperatures.

Table 4-1. Test Results for Natural Gas Fuel

Fuel Flowrate, MMBtu/hr	Combustor Pressure, atm	Combustion Air		Combustor Excess Air	Combustor Exit			Adiabatic Flame Temperature, °F
		Flowrate, scfm	Preheat, °F		O_2, % dry	NO_x, ppm, 15% O_2	CO, ppm, 15% O_2	
0.165	1.4	47	558	75	9.6	3.7	1.1	2,793
0.175	1.4	52	541	83	10.1	3.1	2.4	2,704
0.183	1.4	54	556	83	10.1	4.5	3.2	2,715
0.183	1.5	47	569	57	8.2	2.6	2.5	2,995
0.195	1.4	55	557	75	9.6	6.3	5.3	2,792
0.278	2.0	81	546	78	9.8	2.1	2.2	2,754
0.283	2.0	74	559	61	8.5	2.5	26.1	2,944
0.293	2.0	85	541	78	9.8	2.6	1.7	2,750
0.305	2.0	91	559	83	10.1	3.2	2.9	2,717
0.335	2.0	96	552	75	9.6	4.7	2.9	2,789
0.380	2.0	109	554	75	9.6	4.4	4.3	2,790
0.455	3.2	107	544	44	6.9	5.1	75.1	3,147
0.470	3.2	127	548	65	8.8	3.8	37.0	2,891
0.473	3.3	135	555	75	9.6	3.9	4.3	2,791
0.478	3.1	136	542	75	9.6	3.1	5.9	2,782
0.485	3.3	145	541	83	10.1	3.7	3.5	2,704
0.490	3.0	137	549	71	9.3	4.3	4.3	2,825
0.498	3.3	119	541	46	7.1	7.0	5.3	3,117
0.505	3.3	148	555	79	9.8	5.1	5.2	2,753
0.520	3.0	149	546	75	9.6	5.3	4.8	2,785
0.545	3.1	152	552	70	9.2	3.2	9.1	2,834
0.545	3.3	155	554	75	9.6	3.1	6.0	2,790

Table 4-2. Test Results for LPMEOH™ Fuel

Fuel Flowrate, gal/hr	Fuel Flowrate, MMBtu/hr	Combustor Pressure, atm	Combustion Air Flowrate, scfm	Combustion Air Preheat, °F	Combustor Excess Air, %	Combustor Exit Temperature, °F	Combustor Exit O_2, % dry	Combustor Exit CO_2, % dry	Combustor Exit NO_x, ppm, 15% O_2	Combustor Exit CO, ppm, 15% O_2	Adiabatic Flame Temperature, °F
1.41	0.091	1.48	17.4	196	32	1,738	5.4	3.3	1.3	13.7	3,042
1.60	0.104	1.48	20.4	193	37	1,751	6.0	3.4	1.3	8.7	2,969
2.31	0.150	2.02	38.3	196	78	1,990	9.6	3.4	2.7		3,090
3.28	0.212	2.16	39.4	197	29	2,022	5.0	3.4	1.3	0.0	2,997
4.00	0.259	2.50	50.5	196	35	2,045	5.8	3.4	1.0	0.0	3,099
4.17	0.270	2.97	60.3	189	55	2,069	7.8	3.3	2.3	3.7	2,497
4.85	0.314	3.38	74.9	196	66	2,230	8.7	3.4	3.0	22.0	2,741
4.90	0.317	2.70	58.6	192	28	2,234	4.9	3.4	5.7	27.0	2,624

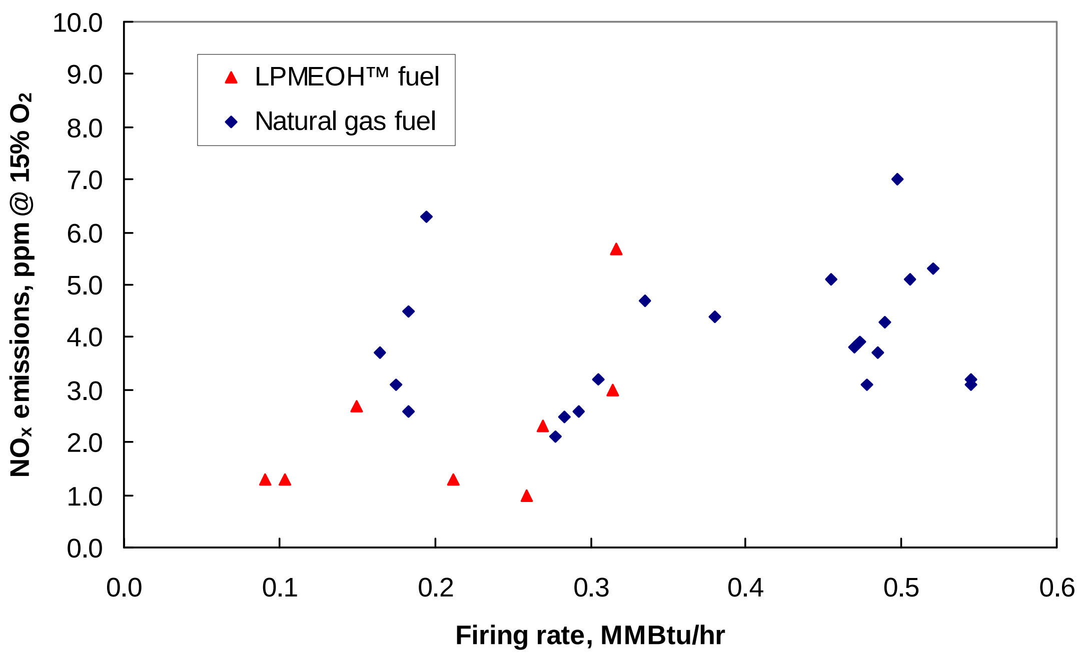

Figure 4-1. NO_x Emissions versus Combustor Firing Rate

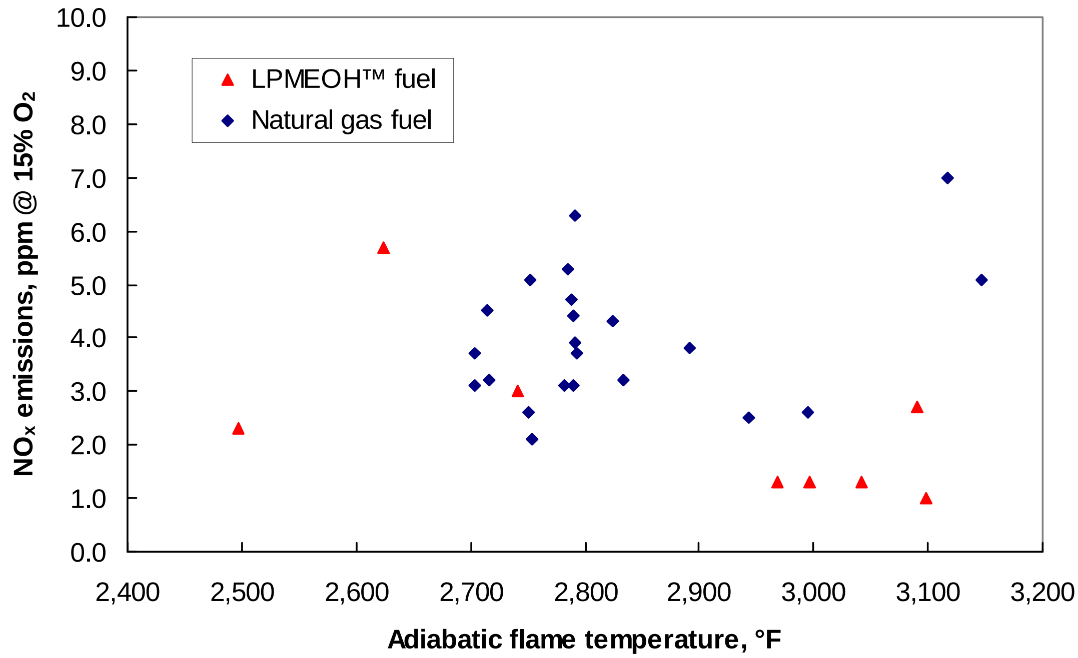

Figure 4-2. NO_x Emissions versus Adiabatic Flame Temperature

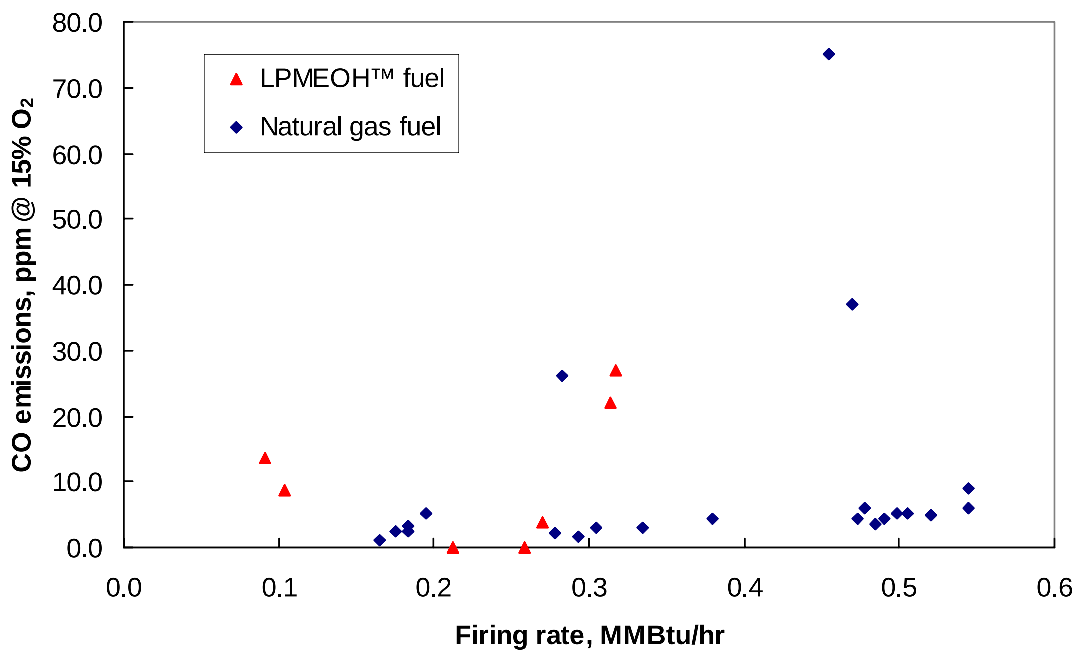

Figure 4-3. CO Emissions versus Combustor Firing Rate

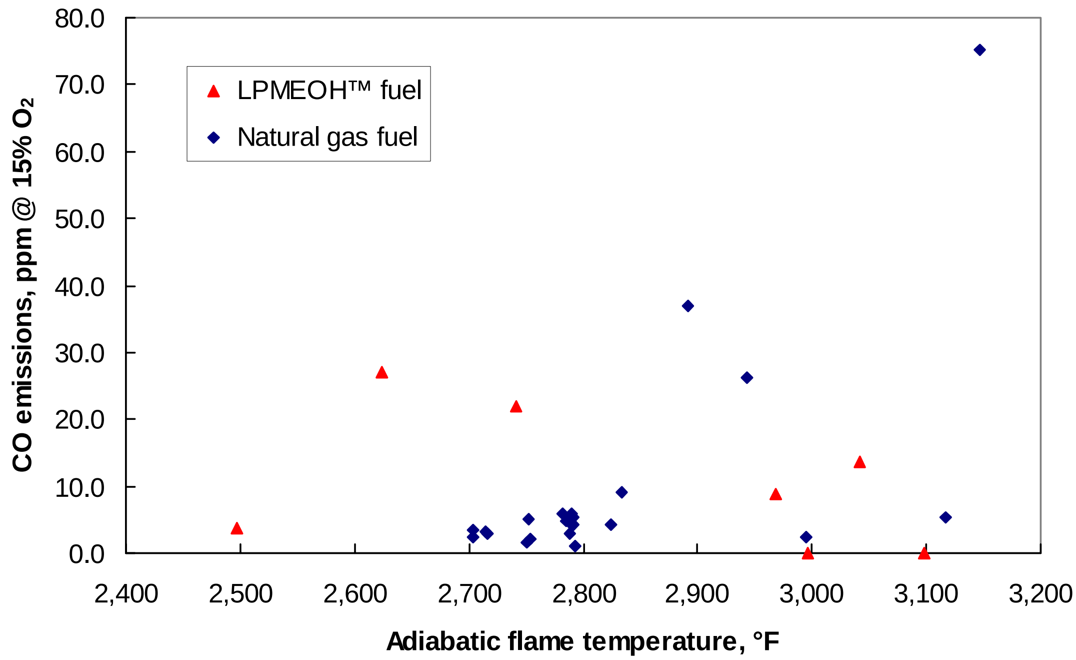

Figure 4-4. CO Emissions versus Adiabatic Flame Temperature

Table 4-3 summarizes the results of the time-resolved measurements taken at the test condition with initial combustor firing rate of 0.259 MMBtu/hr and combustor pressure of 2.5 atm with the LPMEOH™ fuel. Recall that in this test, the combustor flowrate was gradually increased at constant air flowrate and combustor pressure, resulting in a gradual increase in AFT.

The NO_x emissions data in Table 4-3 are plotted versus AFT in Figure 4-5. Indeed, the figure shows that NO_x emissions increase steadily with increasing AFT, as expected. At this air flowrate and combustor pressure, though, NO_x emissions do not exceed 9 ppm at 15 percent O_2, even at AFT greater than 3,330°F. In addition, over the entire test range, CO emissions were uniformly less than 1 ppm at 15 percent O_2, as noted in Table 4-3.

Figure 4-6 shows the same NO_x versus AFT data in Figure 4-5 with the scale of the x-axis expanded to include the AFT of the steady state starting condition for the time-resolved measurements. The starting condition NO_x emissions are shown in this figure as being at the level expected from the logical extrapolation of the time resolved data. This figure shows that a 230°F increase in AFT resulted in a factor of 9 increase in NO_x emissions. This is in keeping with predictions taken from Figure 2-1.

Table 4-3. Time-Resolved Measurement Results

Adiabatic Flame Temperature, °F	Combustor Exit				Combustor Excess Air, %
	O_2, % dry	CO_2, % dry	NO_X, ppm, 15% O_2	CO, ppm, 15% O_2	
3,260	3.3	7.1	2.2	0.2	17
3,262	3.3	8.3	2.2	0.0	17
3,263	3.3	8.4	2.4	0.0	17
3,267	3.2	8.3	2.3	0.2	17
3,270	3.2	7.1	2.5	0.3	17
3,271	3.2	7.3	2.8	0.0	17
3,276	3.1	8.3	2.7	0.0	16
3,282	3.1	7.3	2.9	0.2	16
3,286	3.0	8.5	3.3	0.0	16
3,294	2.9	6.9	3.8	0.0	15
3,296	2.9	8.2	4.4	0.5	15
3,300	2.9	8.4	4.9	0.0	15
3,306	2.8	7.5	5.7	0.1	14
3,312	2.8	8.3	4.6	0.2	14
3,314	2.7	7.6	6.6	0.7	14
3,319	2.7	7.7	7.3	0.3	14
3,321	2.7	6.5	7.5	0.9	13
3,321	2.6	7.0	7.9	0.9	13
3,322	2.6	6.5	6.8	0.8	13
3,323	2.6	7.2	7.7	0.6	13
3,324	2.6	6.8	6.2	0.9	13
3,326	2.6	7.2	6.4	0.5	13
3,327	2.6	6.6	6.9	0.6	13
3,328	2.6	7.1	8.3	0.8	13
3,330	2.6	7.1	7.1	0.7	13
3,331	2.5	6.7	8.6	0.5	13
3,332	2.5	7.5	6.0	0.6	13

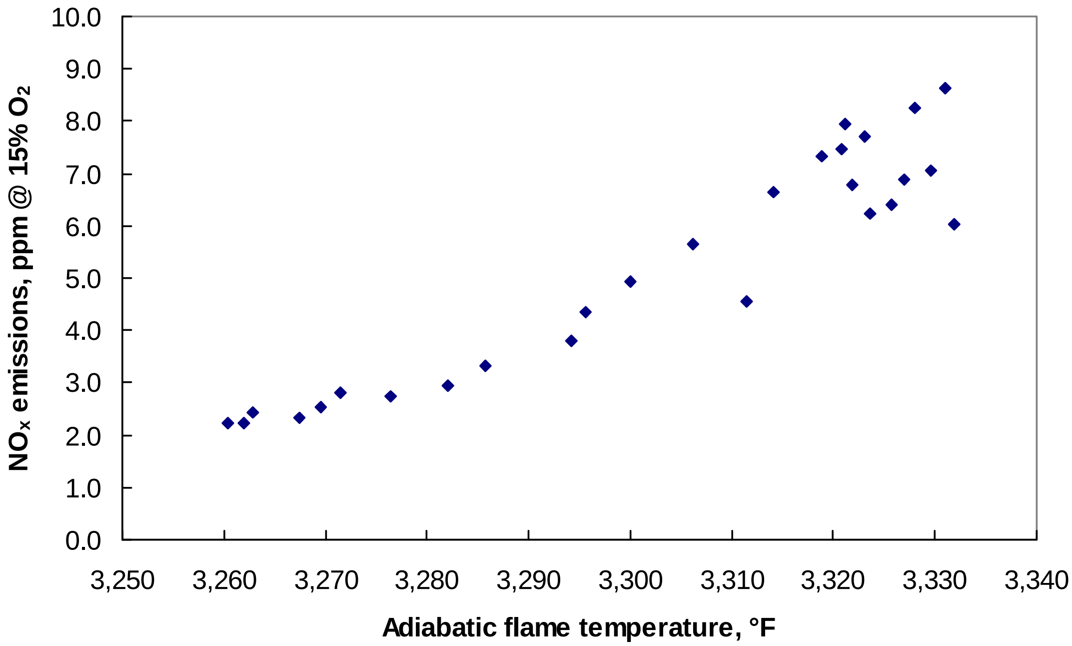

Figure 4-5. Time-Resolved NO_x Emission Measurement Results

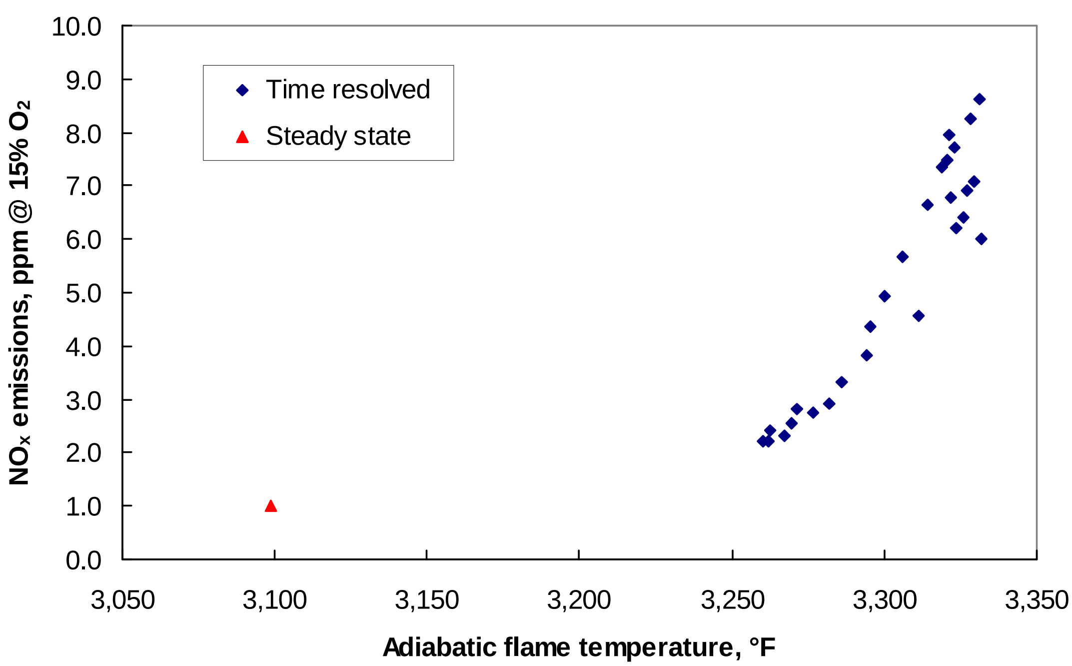

Figure 4-6. Time Resolved NO_x Emission Measurement Results Including Initial Steady-State Condition

5. Conclusions

A series of tests was performed to assess the performance LPMEOH™ as a liquid fuel for a low NO_x microturbine used in a distributed power generation application. The tests were performed in a 10-kW microturbine combustor test facility. Results of the tests showed that combustor NO_x emissions could be held below 6 ppm at 15 percent O_2 over the range of combustor firing rates corresponding to turbine idle to full load. Emissions as low as 1 ppm at 15 percent O_2 were achieved at a number of test conditions, and were 3 ppm at 15 percent O_2 or lower for all but the highest load tested. The low NO_x emissions were achieved with CO emissions at 20 ppm at 15 percent O_2 or lower. In fact, CO emissions were 4 ppm at 15 percent O_2 or lower at all but low load (firing rate) and high load.

Comparing the results achieved with LPMEOH™ fuel to those with natural gas fuel at comparable combustor operating conditions showed that NO_x emissions with LPMEOH™ were the most comparable to and, for several conditions, lower than those with natural gas fuel. CO emissions with LPMEOH™ were also comparable to those with natural gas fuel.

In summary, LPMEOH™ would seem to represent an acceptable liquid fuel for advanced low emission microturbines using the Alzeta GTSB combustor technology, offering emissions performance at the levels achieved with natural gas fuel or even slightly better.